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WORKING PAPER

PROVISION OF DEMAND RESPONSE FROM THE PROSUMERS IN MULTIPLE MARKET

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Prosumers have different choices to maximize their photovoltaic (PV) self-consumption such as demand response (DR) or storage. In this paper, we investigate the prosumers' profits related to the demand response provision. An optimization model is developed which allows the prosumer to bid in DR markets. We focus on two French markets: the NEBEF and the capacity market in which a signal is provided 24h before the real-time. We show that the prosumers are encouraged to provide a DR but the profits are too low compared to the battery investment. We derive a DR premium to foster battery adoption. The premium level depends on the retail rate structure but also on the load curve uncertainty.

JEL CODES : Q20, Q28, Q42.

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KEYWORDS

Prosumers | Energy storage | Subsidies | Demand Response Markets

1. Introduction

Electricity markets have known deep changes over the last decade, going towards more decentralized and smart systems. The deployment of smart appliances, of renewable energies and the objectives in energy efficiency have raised new behaviors for energy consumers. They receive several information to adapt their behaviors, considering the different needs of the electricity grid. Thus, they participate to the grid flexibility, producing or consuming energy when unbalances occur. Besides all support policies to foster the deployment of new technologies (renewable energies, smart appliances), public authorities have also decided to promote photovoltaic (PV) self-consumption. Indeed, the management of renewables raises some issues, both through the increasing of the need in network investments and to the support policy costs. To overcome these difficulties, promoting self-consumption is a new way to create flexibility, to restore the electricity balancing and to reduce the cost of support policies. Unfortunately, several researches showed that solving this equation is not an easy task, self-consumption profitability being uncertain. Indeed, the difference between consumption and production periods reduces the self-consumption rate. To increase it, consumers must change their behaviors. Another idea is that prosumers invest in a Battery System Storage (BSS). However, such technology is not profitable in most of the countries because the retail rate is to low compared to the investment costs. Thus, subsidies are needed to encourage battery investment. Another way of research is to internalize all positive impacts going with this investment. Prosumers can reduce their consumption from the grid during peak periods, decreasing the probability of congestions and creating flexibility to balance the electricity system. Moreover, distribution network operators need to balance their system locally (Richter and Pollitt, 2018); prosumers participate in this local balancing. They reduce their consumption from the grid without disutility (without losses of comfort) because they continue to consume electricity, coming from their BSS (Bartusch et al., 2011). Other studies have shown that consumers want to keep their consumption level (comfort), despite the introduction of incentives. Consumers show a disutility coming from the high frequency of changing behavior of consumption (Newsham and Bowker, 2010). Some consumers, with the increase of prosumers or because of a modification in energy rates to encourage flexibility, could be worse off because of the reduction of cross-subsidies and transfers (Clastres et al., 2019; Simshauser, 2016). The question of disutility is worth of interest. Even if prices are very high, consumers try to keep their comfort and respond to prices with flexible demand (or appliances) only if the comfort remains the same (Alberini et al., 2019). With a BSS, they do not have to modify their habits. However, in all these cases, the remuneration level for the service is monitored, and is often below what investors were expected. Some further incentives should be needed to restore the incentives in self-consumption with BSS.

In our paper, we investigate some solutions to complement all incentives we mentioned previously. We assume that prosumers valorize their self-consumption in flexibility markets, as load-shedding or capacity markets. They earn additional incomes from these new markets which increase the PV system profitability but also their BSS. Thus, our aim is to show that prosumers can make bids on flexibility markets (capacity or load-shedding markets) to reduce unbalances in electricity systems and to increase self-consumption profitability. We show that prosumers have interest to participate in these flexibility markets. However, additional incomes are low and rely on energy prices, on monetary transfers between prosumers and other stakeholders (aggregators, retailers), on the uncertainty on load-shedding consumption and on the penalty level when imbalances occur.

Our paper is organized as follow. In section two, we present the literature related to our problematic. Section 3 develops the flexibility markets we consider in our research. In section 4, we explain our optimization model and our assumptions. Section 5 develops our case studies, the French market. Our results are exposed and analyzed in section 6. In section 7, we conclude and we also make some policy recommendations.

2. Literature

Operating and scheduling demand response allow market participants to make profit on the electricity and reserve markets. In the case of an aggregator, Rious et al. (2015) assessed the profitability of providing demand response (DR) in the day-ahead market (DAM) and the real-time market (RTM). A similar study conducted by Feuerriegel and Neumann (2014) analyzed the revenue stream from different markets but separately. Nolan et al. (2016) proposed a model for participating in multiple markets including the energy, reserve and capacity markets. In the aforementioned studies the problem is solved with a deterministic optimization. Akbari-Dibavar et al. (2019) a hybrid stochastic-robust optimization approach is considered to provide bids in the DAM and RTM. In the same vein, a simulation algorithm is proposed in Staffell and Rustomji (2016) to maximize the profit from reserve bids. Their study focused on the demand bids for a battery storage system (BSS) owner.

With the growing number of distributed energy sources connected into the distribution grid, the provision of demand response from prosumers has received a significant attention. For instance Iria & Soares (2019) estimated the aggregator's profit in the energy market by managing a portfolio of DER sources. They performed an optimization model under deterministic and stochastic environment which allows the aggregator to bid in the energy market. Managing DER sources by this method leads to decrease the aggregator's costs by 20% in both deterministic and stochastic model. However, bid levels are lower under the stochastic model because the expected profit is affected by the expected imbalances. If the whole aggregator's savings is given to the customers, it would represent 1.6€ a week per customer. They show that the k-means model performs well in an environment where uncertainty is high. Moreover, this method is simple to implement.

In a second paper (Iria et al., 2019), the same authors tackled the same topic but they added the possibility of participating in the secondary reserve. Two terms are added to the objective function of the aggregator: revenue of selling band in the reserve market and the expected penalty for band not supplied. The model is also developed in a stochastic environment where balancing costs and participation in the secondary reserve depend on scenarios. In contrast to the study described above, the non-flexible load and PV generation scenarios are determined by using the Gaussian copula method. They showed that the additional participation in the secondary reserve reduced costs by 39% compared to a situation where the aggregator only participates in the energy market. For the prosumers, the savings increased twice and would be 152€/year, i.e. a 40% reduction in the bill. They also showed that flexibility would lead to a reduction in greenhouse gas emissions by decreasing the coal and gas power plants during peak demand.

In the same vein, Nizami et al. (2020) analyzed the prosumer's savings by participating to the energy market via a local market. Unlike the papers mentioned, the authors focused on a residential prosumer without considering the flexibility management by an aggregator. The authors developed a 2-stage stochastic optimization model. The first is the formulation of bids in the day-ahead market and the second is the optimization of sub-problems such as battery ageing and the prosumer discomfort. Uncertainty is modelled using scenarios generated by a Monte Carlo simulation. They show that costs decrease by 51% in winter and 35% in summer compared to a situation without flexible source management. Nevertheless, the simulations were carried out for the warmest week of the summer and the coldest week of the winter.

However, the DER investment is not taking into account. Calvillo et al. (2016) performed a similar study but they analyzed the optimal planning on top of the operation of the DER sources. The aggregator therefore seeks to maximize its revenues on the day-ahead market by optimizing DER investment and operation. A stochastic model has been developed and uncertainty is modelled through a set of scenarios generated by the K-means method. They show that the aggregator profit can be significant, up to 50% in the case of the stochastic model compared to a situation without flexibility management. The aggregator's strategy is the same compared to the papers described above, i.e., buying on the markets during the day, where prices are lower, and selling in the evening. Nonetheless, the comparison of the investment cost and profit was not deeply studied.

A comparison between investment costs and savings was made in Yu (2018a) but without considering the energy market. The author analyzed the electrical system savings from the decreasing of the French peak demand by operating residential batteries. Assuming that all households install PV panels and batteries, battery charge management would reduce peak investment costs by 3.7 billion euros. To encourage households to invest in such systems, the service would have to be remunerated at €56/MWh for installations in Paris (low irradiance) and €24/kWh in Nice (high irradiance).

So, the investment cost has been neglected in the study aforementioned expect to Yu (2018a) but the paper does not focus on the participation of the prosumer in the energy market. To fill this gap, this paper proposes an optimization model which allows a prosumer to bid in two different markets: the day-ahead and capacity markets. The prosumer seeks to minimize the energy procurement cost by operating the battery charge. Two models are formulated: deterministic one and stochastic one which allow us to analyze the impact of uncertainty for a household in the formation of bids. The prosumer's revenue is assessed without considering a transfer from a third party. Then, the break-even point is calculated based on the battery investment costs and the savings from the demand response.

3. Provision of DR in the French case: the NEBEF and capacity markets

In France, Demand Response (DR) is considered as a flexible power plant. DR providers or aggregators make bids on flexibility markets as generators. In our study, we analyze bids made on the DR (NEBEF) and capacity markets[1]. On the first one, the load-shedding energy is remunerated whereas the capacity in the second one. In these two markets, participants received a notification from the market operator the day before the event, which is the load-shedding. Thus, they know the day before if their DR bids will be activated or not. As for classical energy markets, bids on the two markets can be activated simultaneously, increasing the profitability and reducing the missing money issue. In the capacity market, electricity retailers buy certificates according to their customers' consumption level. By decreasing the consumption during notifications in the capacity market, retailers save on the certificate costs and reward the prosumers for the DR. Thus, a prosumer can directly, or via an aggregator or a DR provider[2], makes bids on these two markets to increase the self-consumption profitability. The price is usually based on the marginal price of the day-ahead market (EPEX). We introduce in our analysis data from the year 2018. The NEBEF and capacity markets have sent notifications respectively for 1212 hours and 312 hours in 2018 (Figure 1). Notifications mainly occurred in the winter period, when the electric system is tight, due for instance to the huge use of electric heating.

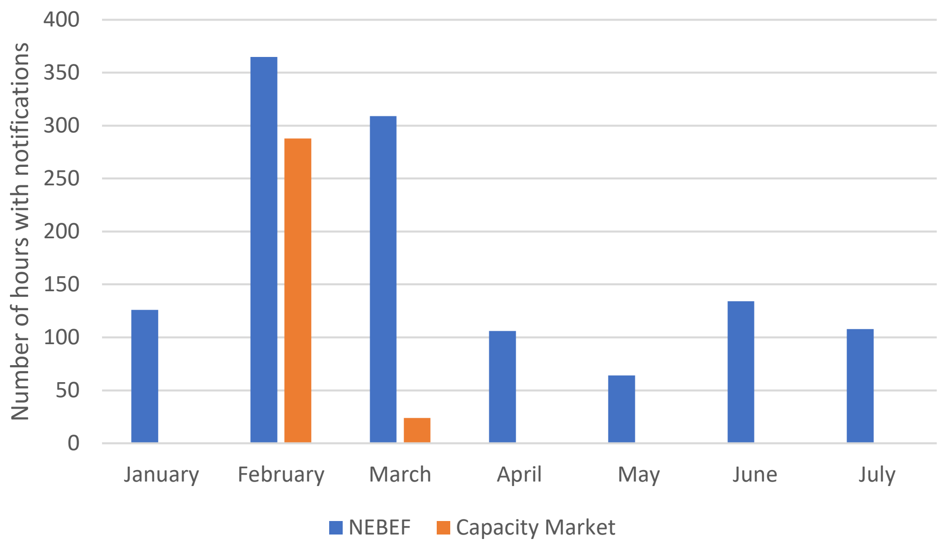

Figure 1: Number of hours with notifications on the NEBEF and capacity markets (Open Data Réseaux Energies, 2020)

[1] For sake of simplicity, we often call these two markets the « DR markets » in the rest of the article.
[2] A Demand Response Providers (DRP) in our analysis can be a prosumer, an aggregator or a Demand Response Provider. In the following of the article, DRP will mainly stand for a prosumer but our analysis stays relevant for the two other stakeholders.

The DR entails relationships between retailers and prosumers or usual consumers. Indeed, the retailers supply electricity to consumers or prosumers. In this last case, the energy supplied is the residual demand if they self-consumed a part or their PV generation. When consumers decide to participate in DR programs, or if retailers propose DR program to consumers (or prosumers), their relationships become more complex. Retailers proposing DR services earn a positive net present value (Feuerriegel et al., 2016). However, they have to compensate some consumers for disutility, in case of high preferences for comfort or if they want to manage DR with direct load controls (Broberg and Persson, 2016; Richter and Pollitt, 2018). However, retailers are not the only operator that propose DR program to consumers or prosumers. Demand Response Providers (DRP), or prosumers themselves, can directly participate in DR markets. Several researches have shown that under DR implementation, the global and peak demand are reduced (Matsukawa et al., 2000; Woo et al., 2017, Di Cosmo et al., 2014), particularly if load-shifting effect (and rebound effect) is reduced. Thus, retailers' activity is riskier, as they negotiate their supplies to serve their forecasted demand. However, a DRP or a consumer can reduce this demand by participating in DR markets. Thus, retailers pay balancing costs in case of unbalances. They can hedge part of the risk contracting strategically on the energy markets but they deal with additional costs. Thus, DRP or consumers, valorizing the DR in DR markets, have to compensate retailers for risk (Crampes and Leautier, 2015). In France, the design of the compensation between retailers and DRP relies on this analysis. DRP that shed part of retailers' demand must compensate them. They pay the energy part of the retail rate to retailers for each load-shedding. In the following of our analysis, we integrate this compensation fee, that is of €50 per kWh (for residential consumer). Then, we will see its impacts on incentives to participate in DR program (DR volumes and profitability of DR strategies). Obviously, this constraint affects the incentives of making bids on DR markets, as the profitability of the DR offers rely on the difference between spot price, that remunerate the DR volumes, and the compensation fee. As figure 2 shows it, the spot price is greater than the compensation fee during 574 hours; the remaining hours are not profitable for DRP because they have to compensate retailers[3].

DRP make bids on the day-ahead market, the NEBEF or capacity markets that are cleared the day before the event (the load-shedding). Thus, they know on a day-ahead basis the DR level they propose for the following day. As uncertainties affect both generation and demand conditions, an imbalance can occur. Indeed, consumption or self-generation can be lower than forecasted. In this case, the bid is not satisfied. The DRP faces a penalty on the balancing market but only if generation is lower than the demand (high settlement tendency on the balancing market), i.e. if the absence of DR creates or increases unbalances. DRP pays the settlement price for these unbalances. Some researchers have shown that it was not efficient to penalize DR, especially if this DR occurs in tight consumption periods or in peak periods (Alexander, 2010; Fenrick et al., 2014). Indeed, a loss of incentives in DR bids is observed in case of strong penalties. We will investigate in the following the impact of penalties on DR

[3] In our analysis, when spot prices are lower than the compensation fee, the DRP does not make bids on the DR markets. The study of several incentives to compensate these losses are beyond the scope of our analysis.

implementation for prosumers. As we could see in the Figure 3, penalties are significant and greater than spot prices. Thus, if the DRP does not fit with its bids on the DR markets, losses from unbalances could offset earnings from DR volumes. According to the NEBEF data, unbalances could account in average for 13% of DR bids. For the year 2018, 11074 MWh were effectively shedded on about 12773 MWh selected by the market operator; this figure stands for 87% of the selected offers that are on average effectively shedded (Open Data Réseaux Energies, 2020).

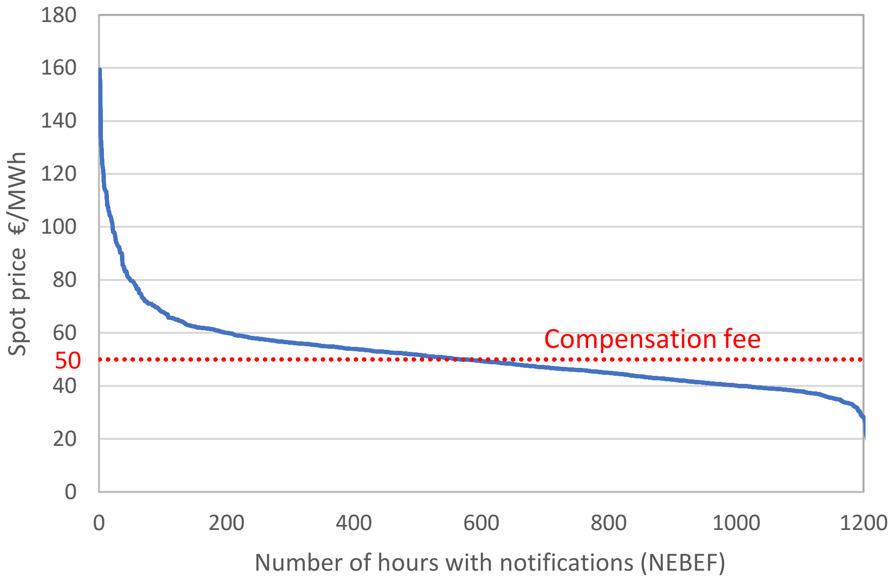

Figure 2: Spot prices and compensation fee when the NEBEF market is activated (Open Data Réseaux Energies, 2020)

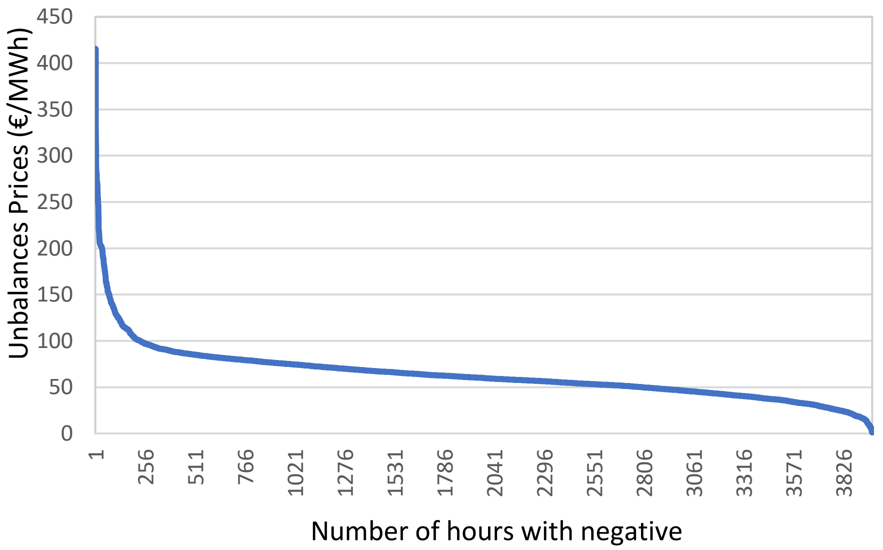

Figure 3: Unbalances prices for negative settlements on the balancing market (Open Data Réseaux Energies, 2020)

4. Model

4.1. Assumptions

We assume a set of prosumers with the following installed technologies: 3 kW PV paired with a 4 kWh because it provides an optimal solution for high self-consumption rates for an average households[4] (Yu, 2018b). This set of prosumers seeks to minimize their annual electricity bill by investing in a BSS in order to decrease their residual consumption from the grid and so, their electricity bill. According to their BSS and PV generation, they have the possibility to provide DR in the energy and capacity markets[5]. We assume that the DR volumes are connected with the self-consumption level that the prosumers anticipate. Prosumers receive a signal from the market operator 24 hours before the real-time and they propose bids to their DRP based on their load and PV generation curves. As mentioned above, the DRP could be prosumers' retailers, another DR operator (aggregator) or the prosumer himself[6]. The DR price in the energy and capacity markets is known. DR is remunerated with the spot price for the energy market and the capacity certificate costs for the capacity market. The BSS is not connected to the distribution grid which mean that the battery cannot discharge electricity into the grid. We also consider three different retail rates (Table 1) : a flat rate, a Time-Of-Use (TOU) tariff with two periods (peak hours are on the following time slots [7am-1pm] – [5pm-1am]) and a TOU with four periods (prices are different in winter and summer). The excess generation is assumed to be sold at the current average market price equal to 44€/MWh minus a margin for the buyer equals to €6/MWh (Rebenaque, 2020).

Table 1: Retail tariffs[7] (Rebenaque, 2020)

Tariff (€/kWh)	Winter: December - March		Summer: April - November	
	Peak	Off-Peak	Peak	Off-Peak
Flat	0.1546			
TOU_2Periods	0.1780		0.1337	
TOU_4Periods	0.1890	0.1390	0.1450	0.1160

For each of these retail rates, we build a set of scenarios that differ each other on some features. First, we assume that prosumers' consumption is deterministic or stochastic. The introduction of uncertainty in demand affects DR volumes. Second, they differ on the presence of the compensation fee. Table 2 summarizes all our scenarios we study in our research.

[4] In the following of our research, we do not analyse the profitability of the PV-battery investment.
[5] To participate in the DR markets, load aggregation is needed and we assume that the prosumers make bids through a virtual power plant.
[6] This assumption does not affect our analysis as we can see it in the following of the article. It is only limited by quantities prosumers could offer on the DR markets. As they offer low quantities or capacities, they certainly have to contract with an aggregator or with their retailers but these contracts are out of the scope of our paper as we want to focus on prosumers' strategies and revenues.
[7] In France, the grid component is composed of a fixed part which represents 20-30% of the grid bill but it is not taking into account.

Table 2: Scenarios of different prosumers' strategy and market design

Scenarios		Flat Tariff	TOU 2 periods	TOU 4 periods
Deterministic Demand	PV (Benchmark scenario)	Prosumers self-consume a part of their PV generation according to the different tariffs		
	Battery	Prosumers invest in a battery to increase self-consumption. They charge it in off-peak hours and they discharge it in peak periods.		
	High_DR_Det	Prosumers are active on the DR markets. The demand is known and they (DRP) do not pay the compensation fee to retailers.		
	Low_DR_Det	Prosumers are active on the DR markets. The demand is known and they (DRP) pay the compensation fee to retailers.		
Stochastic Demand	High_DR_Stoch	Prosumers are active on the DR markets. The demand is uncertain (stochastic) and they (DRP) do not pay the compensation fee to retailers.		
	Low_DR_Stoch	Prosumers are active on the DR markets. The demand is uncertain (stochastic) and they (DRP) pay the compensation fee to retailers.		

4.2. Deterministic model

In the deterministic model, the agent knows perfectly his load and PV generation curves and thus, the amount of demand response (DR_t) which he can provide. The objective function depends on 3 terms. The first term is the electricity bill composed of the residual consumption (C_t^{res}) and the retail price (p_t^{RR}). The second term is the revenue from the selling of the excess generation (S_t) at the fixed spot price (p^{ws}). The third term is the revenue from the demand response composed of the DR and the price (p_t^{DR}) according to which market the DR is provided. In the case of the NEBEF, the prosumer has to compensate the seller by the energy component of the retail rate (p_t^{En}).

Objective function:

$$Min \sum_{t \in T} (C_t^{res} \cdot p_t^{RR}) - (S_t \cdot \bar{p}_t^{ws}) - [DR_t \cdot (p_t^{DR} - p_t^{En})] \tag{1}$$

The deterministic model is subject to the following constraints:

$$L_t = C_t^{res} - S_t + G_t - BSS_t^{in} + BSS_t^{out} \tag{2}$$

$$SOC_t = \mu \cdot BSS_t^{in} - \frac{1}{\mu} \cdot BSS_t^{out} + SOC_{t-1} \tag{3}$$

$$SOC_t \cdot DOD \leq C^{bat} \tag{4}$$

$$C_t^{res} + DR_t^{NEB} + DR_t^{cap} \leq L_t \tag{5}$$

$$C^{bat}, C_t^{res}, DR^{NEB}, DR^{cap}, S_t, BSS_t^{in}, BSS_t^{out} \geq 0 \tag{6}$$

Eq.(2) represents the power balance of the system. It guarantees that the production (G_t) is self-consumed or fed into the grid (S_t) or feed-in the battery (BSS_t^{in}). If the PV generation is not enough to cover the load, the battery is discharged (BSS_t^{out}). Eq.(3) represents the state of charge (SOC_t) of the battery. It depends on the charge and the discharge but also on the SOC at $t+1$. An efficiency parameter (μ) for the inverter is applied during the charge and discharge process. Eq.(4) limits the power flow by the nominal capacity of the battery and the depth of discharge (DOD). Eq.(5) ensures that the DR cannot be higher than the load and that the DR can only be proposed in only one market. Eq.(6) represents the positivity constraint.

Under a TOU tariff, the prosumers seek to maximize the self-consumption during peak periods. If a DR signal occurs during an off-peak period, the battery strategy changes if:

$$p^{DR} > p^{peak} - p^{offpeak}$$

The prosumer is willing to provide a DR response during an off-peak hour only if the price DR price plus the off-peak price is higher than the peak price.

4.3. Stochastic model

In a second model, uncertainty is introduced on the prosumers' consumption. The load forecast is based on a set of stochastic scenarios s. The probability of occurrence of each scenario s is π_s with $\sum_{s \in S} \pi_s = 1$. If the DR at the real-time is lower than the one forecasted 24 hours before, a penalty is applied for penalizing the imbalances. Usually, to implement new technologies or new behaviours, incentives are decided by authorities and they often internalize part of risk investors incur. Thus, DR is often remunerated and not penalized (Alexander, 2010; Fenrick et al., 2014). In our stochastic model, we will compare the impact of penalties on remunerations and DR strategies to point out the reduction of profitability and flexibility. Under the stochastic model, there is one more term than the deterministic one. The first two terms remain unchanged. In the third term, $\left(DR_{s,t} - \Delta C_{s,t}\right)$ represents the DR at the real-time minus the imbalance $(\Delta C_{s,t})$ from an error forecast. The last term represents the imbalance cost with P^{lty} the penalty.

$$\begin{aligned} Min \sum_{t \in T} [\, (C_t^{res} \cdot p^{RR}) - (S_t \cdot p^{ws}) \\ - \sum_{s \in S} \pi_s \left[\left(DR_{s,t} - \Delta C_{s,t}\right) \cdot (p_t^{DR} - p_t^{En}) \right] - (\Delta C_{s,t} \cdot p^{lty})] \end{aligned} \tag{7}$$

The constraints have to be updated to take into account the stochastic scenarios:

$$L_t = C_{t,s}^{res} - S_{t,s} + G_t - BSS_{t,s}^{in} + BSS_{t,s}^{out} \tag{8}$$

$$SOC_{t,s} = \mu \cdot BSS_{t,s}^{in} - \frac{1}{\mu} \cdot BSS_{t,s}^{out} + SOC_{t-1,s} \quad (9)$$

$$SOC_{t,s} \cdot DOD \leq C^{bat} \quad (10)$$

$$C_{t,s}^{res} + DR_{t,s}^{NEB} + DR_{t,s}^{cap} \leq L_t \quad (11)$$

$$C^{bat}, C_{t,s}^{res}, DR_{t,s}^{NEB}, DR_{t,s}^{cap}, S_{t,s}, BSS_{t,s}^{in}, BSS_{t,s}^{out} \geq 0 \quad (12)$$

5. Case study

5.1. Household and technology parameters

The same assumptions from Rebenaque (2020) have been made regarding the PV/load curves, the battery parameters and the battery degradation model. The PV load profiles are generated with the software "Renewable Ninja"[8]. A PV system installed in the south of France which benefits of the highest irradiance is considered. The energy yield in this area is about 1626 kWh/year. A lithium-ion battery based on nickel manganese cobalt (NMC) is considered in this study. The battery parameters are presented in Table 3.

Table 3: Battery parameters (IRENA, 2017; Rebenaque, 2020)

Parameters	Unit	NMC		
		2020	2025	2030
Depth of discharge *(DOD)*	%	90	90	90
Round-trip efficiency (η_{Batt})	%	95	95	95
Self-discharge (φ)	%/day	0.01	0.01	0.01
Battery cost (VAT excluded)	$/kWh	645	465	335

The battery is subject to a degradation over the years and affects the savings. The same model from Beltran et al. (2020) for the battery degradation is used. The nominal capacity is affected by the time ($Ageing_{cal}$) and the energy throughput ($Ageing_{cycl}$):

$$Ageing_{cal} = \alpha_{cal} \cdot e^{\beta_{cal} \cdot T} \cdot (t^{0,5}) \quad (13)$$

$$Ageing_{cycl} = \alpha_{cycl} \cdot e^{\beta_{cycl} \cdot T} \cdot (Nb\_cycles^{0,5}) \quad (14)$$

With Nb_cycles the number of cycles and the parameters in Table 4.

[8] https://www.renewables.ninja/

Table 4: Battery degradation parameter

α_{cal}	α_{cycl}	β_{cal}	β_{cycl}	T[9]
$1.985 \cdot 10^{-7}$	$4.42 \cdot 10^{-5}$	0.051	0.02676	308.15

The nominal capacity at each period is given by:

$$Batt_t = Batt_{t-1} \cdot [1 - (Ageing_{cal_t} + Ageing_{cycl_t})] \tag{15}$$

Th battery is obsolete when $Batt_t$ reaches 0.7, i.e. 70% of the battery capacity. See Beltran et al. (2020) for more explanations.

The Load profiles are generated by a software "LoadProfileGenerator" (Pflugradt, 2016). Two default households are simulated: the first one called "CH05", both parents work outside the house whereas the one called "CH45", one of the parents works at home. They have both an annual consumption of about 4650 kWh and the peak consumption is respectively 4.7kW and 5.2 for CH05 and CH45. However, CH45 has a flatter load curve (Figure 4).

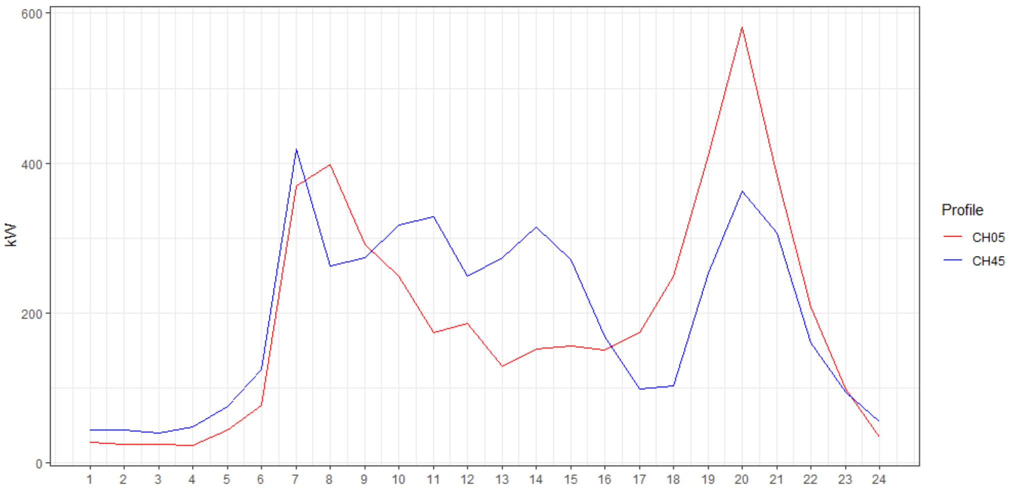

Figure 4: Hourly sum of the consumption within the year

5.2. Definition of Demand Response Strategies

When prosumers participate in DR markets, we assume that they offer some DR volumes or capacities. Their bids are set according to the forecasted demand for the next day. When the demand is known, then DR strategies are equal or lower than the demand, according to the charge of the battery. When the demand is stochastic, we set DR strategies according to the different values of the forecasted demand.

In the stochastic scenario, we use the following methodology to compute the set of strategies and their probabilities. Prosumers make bids on the DR markets associated with a probability to be effectively realized according to the uncertainty on the demand. These sets of quantities have been generated using the K-means algorithm. This clustering method

[9] Temperature in kelvin

classifies n observations $(x_1, x_2, \ldots, x_n)$ into k clusters $S = \{S_1, S_2, \ldots, S_n\}$ such that the squared distances from the cluster are minimized (Iria and Soares, 2019):

$$\arg\min_{S} \sum_{i=1}^{k} \sum_{x \in S_i} x - {\mu_i}^2 \qquad (16)$$

Where μ_i is the mean of point in S_i

The number of observations in a cluster represents the probability associated to the strategy such that the sum of the observations equals to one. Three scenarios or clusters (k_1, k_2, k_3) are considered for each hour of each representative day of each season. The year is divided in 4 seasons composed of three months starting from December to February and so one until November. The number of optimal strategies is determined by drawing the relation between the within sum of square and the number of clusters. The location of a bend indicates an optimal value of number of strategies for each hour. These optimal values are several sets of 3 DR strategies in the most cases (Calvillo et al., 2016).

6. Results

To present our results, we focus on one prosumer and we analyse for each scenario its self-consumption and the DR strategies on each DR markets under deterministic and stochastic demand. We then focus on DR profits. Finally, we finish with a proposition of a premium to encourage the battery investment.

When a prosumer participates in DR markets, it increases the self-consumption savings. This revenue is added to the gains from self-consumption, as savings on energy part of the tariff and transmission costs (Clastres et al., 2019). The DR is valued on the NEBEF at the spot price, and at a price of 41€/MWh on the capacity market; this later price corresponds to the capacity procurement cost in the regulated retail rate (CRE, 2020). In the NEBEF, recalling that a compensation, equal to 50€/MWh, is due to the electricity supplier. The NEBEF is activated 1212h from January to June and 156h for the capacity markets from February to March. The markets are activated at the same time for 135h. In that case, prosumers are remunerated in both markets for the same DR volumes.

6.1. Self-consumption and Demand Response volumes in the flat rate case

We are focusing on the self-consumption volumes during peak and off-peak periods, and on DR strategies on the NEBEF and capacity markets for each scenario. To understand how the battery strategy works, Figure 5 shows the battery strategy according to a scenario without and with DR provision. Under the scenario Battery, the battery discharge occurs at 7pm when the sun is missing. Under DR participation (scenario High_DR_Det), the discharge occurs from 8pm to 10 pm when the spot price is at the highest (about 150€/MWh). During this time frame, the residual load is null to maximize the profits from the DR. The prosumer cumulates DR profit from the NEBEF and the capacity market.

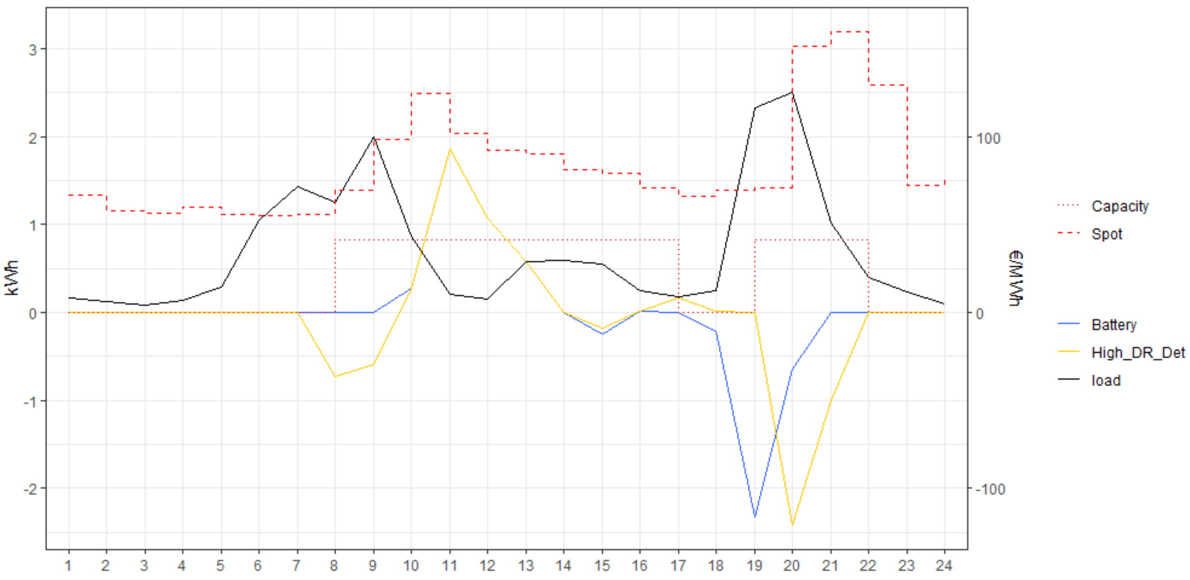

Figure 5: Battery charge strategy (CH45) without DR participation (Battery) and with DR provision (High_DR_Det scenario)

Self-consumption volumes are depicted in Figure 6. Without battery, the self-consumption rate is 31% for CH05 and 41% for CH45. Prosumers self-consume mainly during peak hours (73% for CH05 and 78% for CH45) because most of the peak periods match with the PV generation ones. With a battery, the self-consumption rate is 54% for CH05 and 63% for CH45. The battery allows the prosumer to increase the self-consumption of 70% (CH05) and 53% (CH45) during peak periods. The battery discharge occurs mainly in the evening (corresponds to the peak hours). Thus, 80% (CH05) and 79% (CH45) of self-consumption occurs in peak periods.

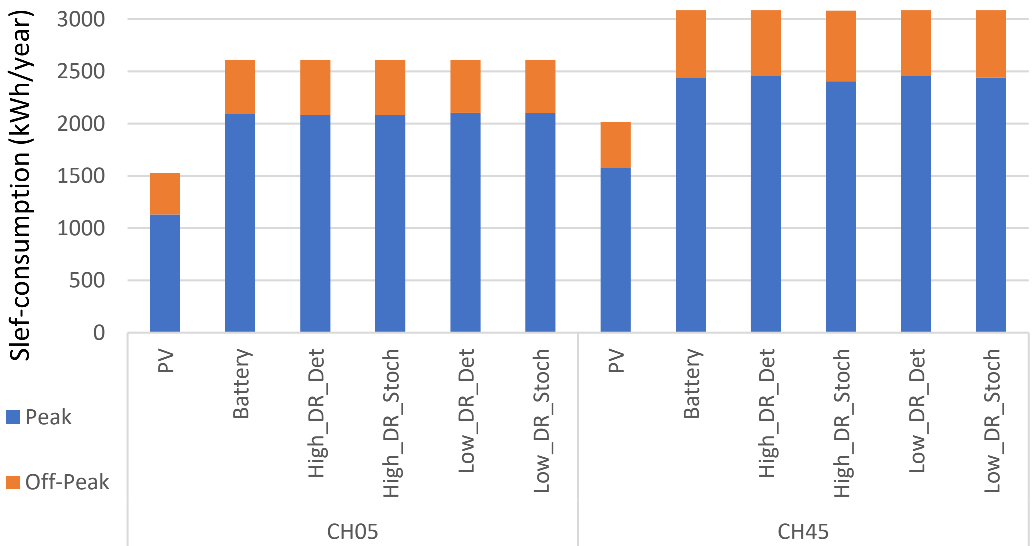

Figure 6: Self-consumption volumes for one year for each scenario and each profile - Flat Rate

In the PV and Battery scenarios, there are no participation in DR markets, thus no signal from market operators to self-consume when DR markets are activated. However, part of self-consumption matches with the DR market periods, as Figure 7 shows it. For the PV scenario, the self-consumption matches well with the DR markets: the self-consumption occurs for each consumer 37% of the time when the NEBEF is activated and 74% for the capacity market. For consumer CH05, it represents 13.4% of his self-consumption (11% for NEBEF + 2.4% for capacity) and 4.4% of his consumption. For consumer CH45, it represents 12.1% of his self-consumption (10% for NEBEF + 2.1% for capacity) and 5.2% of his consumption. For the battery scenario, the self-consumption matches even more with the DR markets compared to the scenario PV: 52% (CH45) and 70% (CH45) of the NEBEF activation and 87% (CH05) and 90% (CH45) for the capacity market. It represents 14.2% (CH05) and 13.4% (CH45) of the prosumer's self-consumption and 8% (CH05) and 8.8% (CH45) of prosumers' consumption. Thus, the battery significantly increases the self-consumption during DR markets periods, even if the prosumers do not participate in these markets.

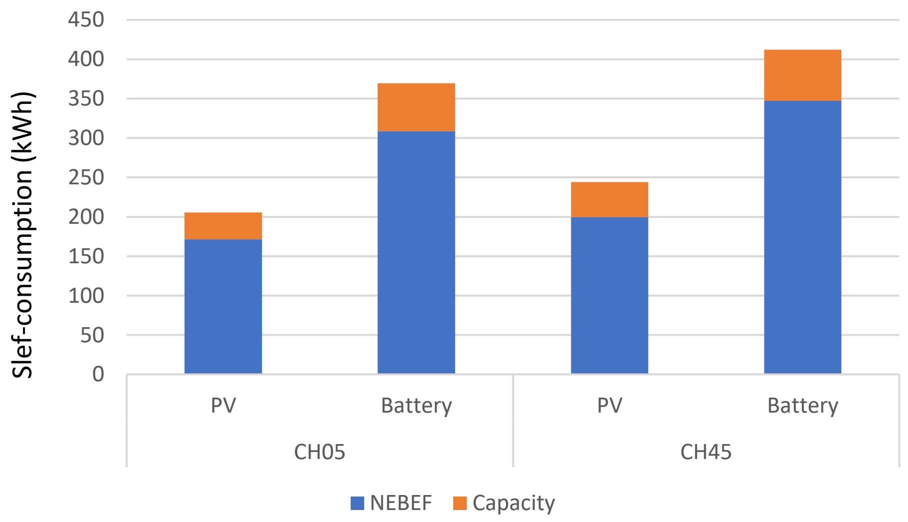

Figure 7: Self-consumption volumes matching with DR markets needs without DR signals

Under all scenarios with DR provision, the overall self-consumption remains slightly the same compared to the scenario "Battery". We notice a slight increase in self-consumption in off-peak hours because of DR signals which also occur in off-peak periods. The DR provision is presented in Figure 8. It stands from 6% to 20% of self-consumption, and from 4% to 12% of consumption (Table 5). The compensation for the electrical supplier has a strong impact on the DR provision. Without compensation, the prosumers bid 79% and 88% of time when the NEBEF is activated whereas in the scenarios with compensation, the prosumer bids only between 39% to 46% of time, when the spot price is higher than €50 (Table 6). Thus, as in the capacity market, there are no compensation, the participation of prosumers stays high (90% to 100%). The uncertainty on the demand has also an impact of the DR strategies (Figure 8 and Table 5). Prosumers reduce their DR bids by 6% of self-consumption. In volumes, when demand is uncertain, consumers CH05 reduces the DR bids on the NEBEF market from 30% (high scenario) to 47% (low scenario) and from 26% for both scenarios on the capacity market. The same trend is observed for consumers CH45 that reduces his DR bids from 32% (high scenario) to 53% (low scenario) on the NEBEF, and from 45% for both scenarios on the capacity market. Uncertainty, added to the compensation to the suppliers on the NEBEF markets, drops the incentives for consumers in participating to the DR markets. These incentives are only reduced in terms of volumes; prosumers continue to respond to DR markets signals, as Table 6 shows it. They actively participate in DR markets in terms of number of hours but each time they reduced the volume of their DR bids. The intuition is as prosumers bid lower volumes on DR markets; some electricity remains in the battery. Thus, they propose the remaining charge in the following DR activations. Thus, the number of hours in which prosumers are actives increases.

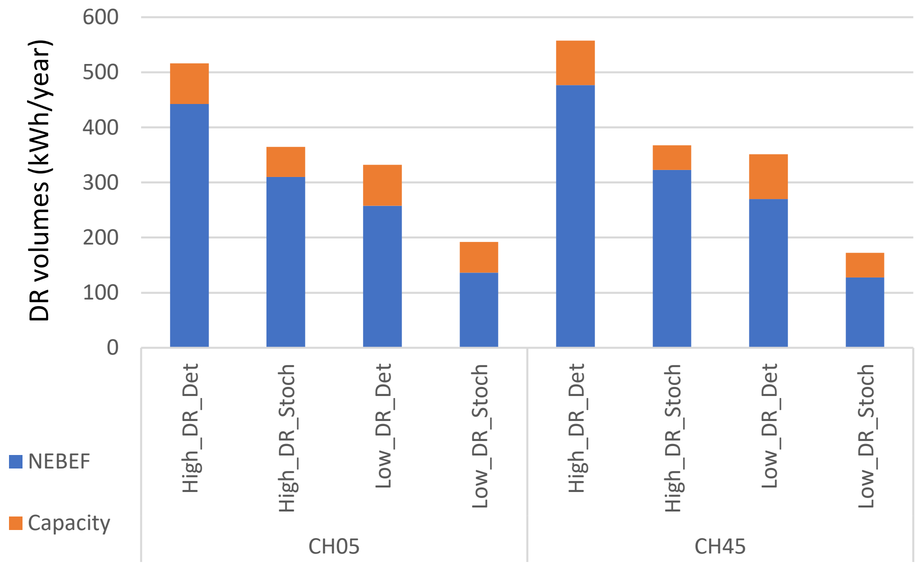

Figure 8: DR volumes on the DR markets with market operator signal – Flat rate

Table 5: Share of DR volumes in consumption and self-consumption (%) – Flat rate

Consumers	CH05		CH45	
Scenarios	% of consumption	% of self-consumption	% of consumption	% of self-consumption
High_DR_Det	11%	20%	12%	18%
High_DR_Stoch	8%	14%	8%	12%
Low_DR_Det	7%	13%	8%	11%
Low_DR_Stoch	4%	7%	4%	6%

Table 6: Participation (in %) of prosumers in DR markets

Consumers	CH05		CH45	
DR Markets / Scenarios	NEBEF	Capacity	NEBEF	Capacity
High_DR_Det	79%	92%	83%	94%
High_DR_Stoch	88%	99%	88%	99%
Low_DR_Det	39%	90%	41%	94%
Low_DR_Stoch	43%	99%	46%	100%

The analysis of Figure 7 and Figure 8 shows that prosumers offer higher volumes on the DR markets only for the scenario in which the future demand is known and without the compensation to the retailers. Indeed, the uncertainty and the compensation fee reduce the DR volumes that could be proposed on DR markets, regards to the case of no bids on DR markets. Thus, if the DR markets impose too many constraints to the prosumers, it will damage the availability of DR volumes. However, as we could see it in the following, prosumers are encouraged to participate in DR markets because they earn additional incomes from DR sales.

6.2. DR profits for a prosumer under flat rate

A prosumer participates in DR markets to increase its self-consumption profits and the profitability of its battery. For each scenario, we compute the revenues from DR sales and analyze the incentives for prosumers to participate in DR markets.

Prosumer's profits are respectively €27.3 and €29.4 for CH05 and CH45 (Table 7). The profits from the NEBEF are higher than the capacity market because the NEBEF activations are much higher. Moreover, the average DR price is €51 in the NEBEF and €41 in the capacity market. The average DR bids is about 0.5 kWh per hour in both markets. The DR markets are sometimes activated during the night and afternoon when the consumption is low. That is why the average DR bids are quite low.

Table 7: Net profits (per year) for a prosumer in the deterministic case with DR and no compensation fee to suppliers

Scenario High_DR_Det	CH05		CH45	
Market	NEBEF	Capacity	NEBEF	Capacity
DR (kWh)	443	73	477	81
Occurrence (h)	954	143	1 012	147
Profit on each DR market (€)	24.1	3.2	25.9	3.5
Overall profit (€)	27.3		29.4	

Table 8 shows that profit stays positive but it decreases by about 35% for CH05 and 39% for CH45 in the stochastic model compared to the deterministic one. There are 2 reasons. First, the average DR bids is much lower under the stochastic model: 0.29 kWh whereas 0.5 kWh in the deterministic model. The prosumers propose a lower DR to avoid the risk related to the penalty. For instance, CH05 proposes the lowest expected DR 86% of the time. Second, the penalty decreases the overall profit. It represents 20% of the DR profit. The imbalances represent between 18% and 24% of the DR activated.

Table 8: Net profits (per year) for a prosumer in the stochastic case with DR and no compensation fee to suppliers

Scenario High_DR_Stoch	CH05		CH45	
Market	NEBEF	Capacity	NEBEF	Capacity
DR (kWh)	280	54	272	45
Occurrence (h)	1 067	154	1 067	154
Profit on each DR market (€)	19.7	2.6	21	2.2
Imbalances (kWh)	60.4	5.4	80	6
Penalty (€)	3.8	0,7	4.6	0.5
Overall Profit (€)	17.8		18.1	

In the low scenario, the prosumers propose a DR only if the spot price is higher than €50, i.e. the compensation to the supplier. This scenario is presented in Table 9 and we compare it with the "High_DR_Det" scenario. The DR amount is lower but only in the NEBEF: -58% for CH05 and -57% for CH45. This is intuitive because the compensation concerns only the NEBEF market. The profits decrease of about €20.8 (76%) and €22 (75%) respectively for consumers CH05 and CH45. The average DR remains the same. The profit from the capacity market is similar to the NEBEF while the DR volumes in the former market represents 28% of the NEBEF. The compensation for the electricity supplier has a strong impact on the profit and, despite positive profits, on incentives to bid on DR markets.

Table 9: Net profits (per year) for a prosumer in the deterministic case with DR and a compensation fee to suppliers

Scenario Low_DR_Det	CH05		CH45	
Market	NEBEF	Capacity	NEBEF	Capacity
DR (kWh)	258	74	270	82
Occurrence (h)	478	140	495	146
Profit on each DR market (€)	3.3	3.2	3.8	3.6
Overall profit (€)	6.5		7.4	

Table 10 shows the same conclusions as we have drawn from the "High" scenarios. With the compensation fee, the uncertainty of demand drastically reduces the profit compared to the deterministic scenario but the number of occurrences is higher. On the NEBEF, the DR amount decreases by about 48% for CH05 and 53% for CH45. However, the imbalances represent between 10% and 14% of the DR activated (between 18% and 24% in the "High" scenario). The profits are positive but close to zero. The impact of the compensation fee is strong in this scenario because the penalty is almost always higher than the DR price. So, the prosumers always propose the lowest expected DR volumes. This scenario is clearly the riskiest for the prosumers. Adding a compensation fee to retailers when the demand is uncertain acts as a drop in incentives to bid on DR markets. However, these incentives always exist as the profit stays slightly positive.

Table 10: Net profits (per year) for a prosumer in the stochastic case with DR and a compensation fee to suppliers

Scenario Low_DR_Stoch	CH05		CH45	
Market	NEBEF	Capacity	NEBEF	Capacity
DR (kWh)	136	56	127	45
Occurrence (h)	525	155	555	156
Profit on each DR market (€)	2	2,7	1.9	2.2
Imbalances (kWh)	13.2	5.4	18	6
Penalty (€)	1.2	0.7	1.3	0.5
Overall Profit (€)	2.8		2.3	

6.3. A premium to compensate additional costs of battery investment – Flat rate

In this section, we compare the profit from the battery and the costs to compute a premium to reach the break-even point. We assume that the excess generation is sold at the average spot price of 3.8 cts€/kWh (Cf 5.1). This term represents an opportunity cost. Indeed, if PV production is stored and self-consumed, the prosumer does not earn the feed-in-tariff for PV energy fed into the grid. The battery profitability depends on two parameters. Firstly, it depends on the gap between the retail rate and the excess generation price. Prosumers earn this price for each self-consumed kWh because it saves the retail rate equal to 15.46 c€/kWh. Secondly, it depends on the profit on the DR market (Table 11)

Table 11: Average gains per kWh on DR markets (c€/kWh)

Scenarios/Consumers	CH05	CH45
High_DR_Det	5.3	5.3
High_DR _Stoch	6.1	6.3
Low_DR _Det	2	2.1
Low_DR _stoch	2.5	2.4

According to the Table 3 and as we assumed a battery with a capacity of 4 kWh, we derive the total battery investment cost equals to €2580. This investment must be recovered over the battery lifetime, i.e. 14 years. Then, we compute the Levelized Costs of Storage (LCOS), using the actualized energy offloaded from the battery. Results are presented in Table 12. The LCOS is about c€24.5 per discharged kWh.

Table 12: Levelized Cost Of Storage (LCOS)

Consumers	CH05	CH45
Actualized Offloaded Energy (kWh)	10,517	10,580
LCOS (c€/kWh)	24.5	24.4

Each kWh from the battery is self-consumed and comes from the PV plant. Thus, prosumers earn the retail rate. As this kWh was stored, prosumers lose the opportunity cost, i.e. the average spot price it would have received if had fed the production into the grid. Thus, for each kWh discharged, the prosumers earn the Levelized Value Of Storage (LVOS) which is computed as the retail rate minus the opportunity cost. The LVOS is then c€11.7 much lower than the LCOS. Then, it is easy to compute the remaining investment cost to recover (Table 13).

Table 13: Overall gains from actualized energy Offloaded and battery costs – Flat rate

Consumers	CH05	CH45
Overall gains from Offloaded Energy (€)	1,226	1,234
Remaining investment cost of battery (€)	1,354	1,346

As we have seen, the battery investment increases the prosumer's self-consumption, thus its savings. However, it also increases the prosumer's costs it has to recover. We propose to compute the premium that is needed to finance the battery. Indeed, the battery increases the self-consumption, reduces peak consumption and gives to the prosumer the opportunity to participate in DR markets. Thus, it creates benefits and added values to the grid and the electricity system. As we study the participation in DR markets, we first compute the premium only based on DR volumes (Table 14). Our result shows the premium per DR kWh is higher when uncertainty occurs and if prosumers must compensate suppliers. This compensation fee has a greater impact than demand uncertainty as it is greater in the scenario « Low_DR_Det » than in the scenario « High_DR_Stoch ». The premium level shows that revenues on the DR markets stay low compared to the investment. Public authorities or regulators must decide subsidies to finance the battery investment.

Table 14: DR premium for each kWh offloaded and offered in DR markets (c€/kWh) – Flat rate

Scenarios	CH05			CH45		
	Actualized DR quantities (kWh)	Overall gains from DR markets (€)	DR fee (c€/kWh)	Actualized DR quantities (kWh)	Overall gains from DR markets (€)	DR fee (c€/kWh)
High_DR_Det	5,636	298	18.7	6,087	321	16.8
High_DR_Stoch	3,982	244	27.9	4,012	253	27.2
Low_DR_Det	3,626	72	35.4	3,837	80	33
Low_DR_Stoch	2,100	52	62	1,881	45	69.2

The DR premium needs to be set at a high level to recover the battery costs. To lower it, public authorities or regulators could decide to increase the incentives to use the battery. For instance, a premium applied to the overall offloaded energy. We saw that prosumers earn positive profits on the DR markets. Thus, we compute this new fee only for the scenarios using DR markets (Table 15). Moreover, the revenue from DR markets could stand for a significant part of the remaining battery costs, between 18 and 24% for the scenario without the compensation fee (with the compensation fee, these figures drop between 3 to 6%). The premium level always relies on the existence of the compensation fee and the uncertainty on demand. However, the amount per kWh is lower, in a range of c€10 to c€12 per offloaded kWh.

Table 15: Premium per offloaded kWh from the battery (c€/kWh) – Flat Rate

	Consumers	
	CH05	CH45
High_DR_Det	10	97
High_DR_Stoch	10.6	10.3
Low_DR_Det	12.2	12
Low_DR_Stoch	12.4	12.3

These results are also linked with the battery cost. As there are currently numerous researches on batteries, their cost is willing to be reduced in future years, as shown in Table 5 (the cost could be reduced by 30% in 2025). Thus, the fee will decrease with the battery cost (Figure 9).

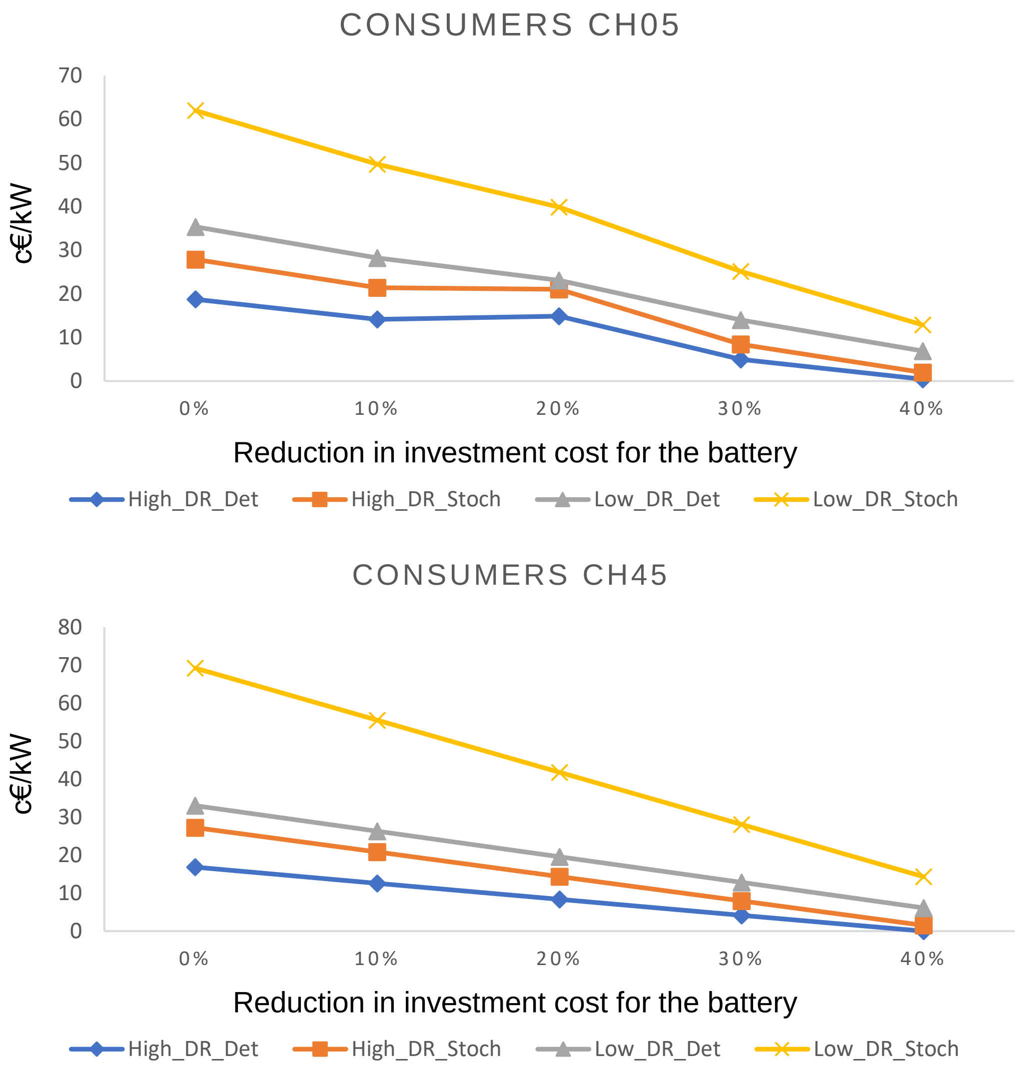

Figure 9: DR premium and reductions in battery investment costs (c€/kWh) – Flat rate

However, a 40% fall of the investment costs is needed to avoid the premium. Moreover, this is only done for the scenario without any risks (no compensation fee and no uncertainty on demand). When prosumer faces to a riskier environment, this figure grows up to 50%. The premium based on the overall offloaded kWh from the battery leads to the same analysis, with lower fee levels[10]. Without compensation fee, a drop in investment costs of 40% allows the prosumer to recover all the battery cost battery without any subsidy.

This analysis shows again the important role of the compensation fee, that could reduce incentives to participate in DR markets, more than the uncertainty on demand. We show that the premium to compensate additional investment cost of the battery is needed in the absence of huge efficiency gains in battery costs. When prosumer has decided to invest in a battery, this premium is lower in the case of DR provision, as revenues from DR markets are positives in all DR scenarios. However, when the compensation fee is paid and with the uncertainty of demand, these revenues are not tremendous and account for a few euros per year.

6.4. Self-consumption and participation in DR markets with a Time-Of-Use tariff

The existence of a Time-Of-Use (TOU) tariff affects the prosumers' revenue, as prices are different in peak and off-peak periods. Thus, savings in off-peaks hours are lower than in a flat rate and, obviously, are greater in peak periods. Thus, two remarks can be made. Firstly, the battery investment increases the self-consumption in peak hours and so, the overall savings. Secondly, as DR markets can be activated in off-peak hours, it reduces DR revenues. Thus, a TOU can decrease the prosumers participation in these markets.

The introduction of TOU tariffs do not modify the self-consumption rates. They are always around 53% for CH05 and 63% for CH45. However, the self-consumption occurs in peak rather than in off-peak periods. During peak hours, it goes from 80% (flat Tariff) to 84% (CH45) and 87% (CH05). The gap between peak and off-peak tariffs involves that prosumer prefers to increase his self-consumption in peak hours to increase his revenues. The battery allows him to implement this strategy. The difference between the two profiles is explained by their load profiles. The profile CH45 has a flatter load curve which means that his consumption his higher in off-peak periods (from 2pm to 4pm) and lower in peak periods.

The incentive to bid on DR markets remains the same. However, the implementation of TOU tariffs reduces both the number of hours of prosumers' bids on the DR markets and the volume of their offers. This reduction only affects the NEBEF market, and not the capacity market, in which the activity was lower yet with lower constraints. Another explanation is that market operators activate capacity market at peak hours. Thus, it does not change the prosumers' strategy. Prosumers always participate more on the NEBEF market than on the capacity market. However, volumes are reduced from 8 to 16% and occurrence from 5 to 8%, only in the high scenarios (Table 16). In the low scenarios, TOU tariffs have no impact on volumes, and a very few impacts on the occurrence of DR strategies (only 1 or 2%). As the risk is important, prosumers have reduced the activity on DR markets. The tariff does not affect this activity: they bid on the markets at hours with a higher remuneration, the compensation

[10] These fees are in a range of c€10 (0% of reduction in costs) to c€0 (40% of reduction in costs) per kWh for the high scenarios and a range of c€12 to c€2 for the lower ones. These intervals are not very different between the two kinds of consumers.

fee playing the role of a strong constraint. We also remark that the decrease in DR volumes is bigger for consumer CH45. The risk on demand reduces volumes and occurrence for all consumers.

Table 16: Reductions in volumes and occurrence of DR bids on the NEBEF market

	Scenarios	Time-of-Use Two Periods		Time-of-Use Four Periods	
		CH05	CH45	CH05	CH45
Volumes	High_DR_Det	-8%	-9%	-7%	-9%
	High_DR_Stoch	-10%	-16%	-8%	-15%
Occurrence	High_DR_Det	-8%	-6%	-6%	-5%
	High_DR_Stoch	-7%	-5%	-6%	-5%

Obviously, as self-consumption increases in peak hours, the revenue from self-consumption is higher under TOU, and maximum for the TOU with two periods. But it is not the case for the DR revenues. The uncertainty on demand does not affect penalties when demand is uncertain. However, as DR volumes decreases, the revenue from DR on the two markets is reduced, but it is always positive. Major impacts are again in the high scenarios, DR revenues of the low scenarios moving from less than 1%. This revenue decreases from 3.8 to 5.4% (Table 17). This last figure is explained by the large decrease in DR volumes, that is not compensated by the decrease in tariff in summer period. The peak tariff does not compensate the decrease in DR volumes and the decrease in off-peak prices.

Table 17: Values (€) and Variation (%) in DR revenues for the high scenarios with TOU

	Time-of-Use Two Periods		Time-of-Use Four Periods	
	CH05	CH45	CH05	CH45
High_DR_Det	-4.7%	-5.4%	-3.8%	-4.8%
High_DR_Stoch	-5.2%	-8.5%	-4.7%	-8%
DR revenues - High_DR_Det	€284	€304	€287	€305
DR revenues - High_DR_Stoch	€231	€232	€232	€233

Under a TOU tariff, the overall energy discharged is different: CH05 increases his offloaded energy from 5.6% whereas CH45 slightly reduce it. Thus, the LCOS is decreasing for CH05 et remains stable for CH45 (Table 18). The structure of the TOU does not change the use of the battery, only the load profile matters.

Table 18: Levelized Cost of Storage with TOU tariffs

Tariffs	Time-of-Use Two Periods		Time-of-Use Four Periods	
Consumers	CH05	CH45	CH05	CH45
Actualized Offloaded Energy (kWh)	11,105	10,489	11,105	10,489
LCOS (c€/kWh)	23.2	24.7	23.2	24.7

Considering the same methodology as in previous sub-section 6.3, we obtain the revenue from this offloaded energy with TOU tariffs. These revenues are greater than in the flat rate for both TOU and each consumer. This is intuitive and related to the increase in self-consumption in peak hours (Table 19).

Table 19: Overall gains from actualized offloaded energy and battery costs – Flat rate

Tariffs	Time-of-Use Two Periods		Time-of-Use Four Periods	
Consumers	CH05	CH45	CH05	CH45
Overall gains from Offloaded Energy (€)	1,548	1,417	1,446	1,326
Remaining investment cost of battery (€)	1,032	1,163	1,134	1,254

Considering the overall gains in DR markets and the remaining battery cost to recover, we compute the premium that public authorities could apply to finance the remaining costs. As in the previous case, this premium is computed on the DR volumes and on offloaded energy. TOU tariffs increase the revenue from self-consumption, and the value of offloaded energy, as we demonstrated it. This increasing value overcomes the reduction in DR revenues. Thus, the amounts of the premium per kWh to finance the remaining costs of the battery are substantially reduced compared to the flat rate case (Table 20). Thus, TOU tariffs improve the impact of self-consumption with battery. Reductions are greater for a two periods TOU and for CH05. This is consistent with all our analysis. In the summer period, lower tariffs are applied and reduce the revenue compared to the TOU tariff. TOU tariffs improve all the features for CH05 whereas they damage some economic values for CH45 consumers. All these effects are reduced for CH45, in the High scenarios and for the TOU_4Periods. All the positive effects of TOU are reduced for these consumers. Revenues from DR strategies are deeply affected by the compensation fee and the battery use is lower than in the flat rate case. Thus, the fee per DR kWh increases (Table 19). We also notice that investment cost decreasing has a positive impact on the reduction of the premium. With TOU tariffs, lower reductions in BSS costs are needed to make this technology profitable (Table 19 and Figures 7).

Table 20: Reductions in the premium to finance remaining costs of the battery between flat and TOU Tariffs

Scenarios	Time-of-Use Two Periods				Time-of-Use Four Periods			
	Premium per DR kWh		Premium per offloaded kWh		Premium per DR kWh		Premium per offloaded kWh	
	CH05	CH45	CH05	CH45	CH05	CH45	CH05	CH45
High_DR_Det	23,5%	8,7%	32,9%	15,2%	14,5%	0%	24%	6,4%
High_DR_Stoch	21,4%	1,1%	31,6%	13,8%	12,5%	-12%	23,1%	1,4%
Low_DR_Det	25,1%	13,9%	29%	13,5%	17,2%	6,6%	21,5%	6,2%
Low_DR_Stoch	25%	13,8%	28,7%	13,1%	17,2%	6,8%	21,2%	6%

To close this sub-section, we note that the implementation of TOU tariffs gives incentives to self-consume and to use the battery, particularly for consumers CH05. However, they could reduce the incentive to participate in DR markets, especially if DR volumes are activated in off-peak hours. The difference in rates between peak and off-peak periods give an incentive to prosumers to increase their self-consumption in peak hours. There are lower incentives to offer

DR volumes in off-peak periods, especially if there a compensation fee or some uncertainties on the demand.

7. Conclusions and policy implications

A lot of countries and public authorities encourage electricity self-consumption generated by renewables, as photovoltaic power plants. To increase this self-consumption, several public policies exist, going from the exemption to some features of retail rates to premium for each self-consumed kWh. Prosumers can also invest in a BSS to increase their self-consumption rate, and to achieve a better matching between generation and consumption periods. However, in some countries, such as France, this investment is not profitable. As we have seen, retail rates are often below the LCOS. Thus, we investigate some solutions to increase this profitability.

The first one is the opportunity for prosumers to participate in DR markets. We analyze the case of the NEBEF and the capacity markets in which consumers receive a signal for load shedding to balance the electricity system. Moreover, prosumers implement DR programs without losses in their comfort if they invest in a battery, as their consumption stay the same. The participation in DR markets creates further revenues for self-consumption but also deals with new uncertainties: a compensation fee on the load shedding and the uncertainty on prosumers' future demand. DR revenues are positives, so the prosumers have an incentive to participate in DR program. These revenues are maximum with a flat rate, a TOU reduces them. Moreover, these revenues are strongly dependent on the compensation fee. This fee allows retailers to internalize part of the risk they incur for imbalances. The payment of this fee also refers to discussions on the consumer's baseline. It increases the DR efficiency by reducing excessive remuneration and thus inefficient DR (Chao, 2011; Crampes and Léautier, 2015). If the retailer is also the DRP provider, the supplier benefits from positive externalities from DR volumes. The compensation fee could be adapted because of DR avoids retailer's imbalances. In others words, if retailers contribute to the balancing market, DR could avoid costly settlements. Thus, retailers reduce their imbalance costs; prosumers could benefit to this reduction. In some cases, It could be efficient that the DRP (retailer) remunerates consumers (prosumers) for their load-shedding (Orans et al., 2010). If the DRP and retailer are different entities, then the compensation fee is due. Prosumers pay the fee and their revenue decreases, reducing the profitability of DR volumes. An analysis of others economic policies, or an adaptation of existing ones, to internalize retailers' risk could be done but this analysis goes beyond this research. Some intuitions lead towards some exemption of taxes and costs on DR volumes that comes from self-consumption, or for a new distribution of revenues from imbalance settlements to finance the risk of suppliers. For instance, public authorities could reduce compensation, considering positive impact of both self-consumption and DR. This kind of exemptions has been done for others new energy technologies to foster them.

The second one is to give a subsidy for the load-shedding or for each offloaded kWh from the battery. We have seen that these premiums must be high, and are increasing with the uncertainty and the compensation fee. However, their level drop with two variables: the existence of TOU tariffs and the efficiency gains in BSS costs. TOU tariffs decrease the profitability of DR volumes, which are mainly in off-peak hours. But they increase the value of self-consumed energy. Thus, the outcome is positive. The decrease in BSS costs also reduces the LCOS. Thus, lower retail rate must be achieved to make the battery profitable. Considering only the DR volumes to set the premium is not efficient, except if BSS costs are reduced from at least 40%. Forecast show that this reduction could be around 20% in 2025. Thus, a fee based on offloaded energy seems to be more efficient, prosumers being interested in maximizing the use of their battery. Moreover, it avoids transaction costs relative to the DR provision.

This research focus on the prosumers and their revenues in several scenarios. Thus, we have not integrated all the gains for the system coming from self-consumption and DR programs. In further researches, it should be interesting to integrate them to analyze their impact on the fee. We have also seen that we do not address the impact on welfare in our research. The consequences of the design of the fee on welfare is worth of interest, comparing a simple self-consumption case with a more complex one, integrating for instance a BSS and flexibility markets.

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